2006 Electric Report to the Regulatory Flexibility Committee of the Indiana General Assembly

Indiana Utility Regulatory Commission

PURPOSE AND SCOPE OF REPORT

This report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b). The report outlines the status of the Indiana electric utility industry. The report reviews the activities of the electric industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 2005 Electricity Report.

EXECUTIVE SUMMARY AND HIGHLIGHTS

Most people take electricity for granted until they suffer an interruption or receive an unexpectedly large bill. There is no doubt, however, that electricity continues to be a major driving force in our nation's economic prosperity and our quality of life. The improvements in technology require adherence to increasingly stringent standards for reliability and quality of service to satisfy the need of sensitive electronic equipment in our homes and businesses.

In Indiana, five major investor-owned electric companies, 72 municipally-owned and 39 distribution cooperatives supply electricity to Hoosiers. Increasingly complex and costly federal environmental regulations and the increasing price of fuel are the primary factors causing increases in the cost of electricity. The recovery of costs associated with increased coal and natural gas prices as well as the costs associated with the installation of new pollution control equipment have resulted in recurrent cost recovery proceedings before the Commission. Customers will also realize some costs from their power supplier's participation in Regional Transmission Organizations ("RTOs"—the Midwest ISO in Carmel or the PJM Interconnection). However, the Commission believes that the costs of participation in RTOs will be more than offset by the improved reliability and increased economic efficiency of electric operations. Customers, in the future, may also see additional costs and benefits associated with the federal Energy Policy Act of 2005.

Energy Policy Act of 2005

In August, 2005, the comprehensive Energy Policy Act of 2005 ("EPAct 2005") became law. It was the first major energy policy legislation in thirteen years. Major provisions of the act included:

- Repeal of the Public Utility Holding Company Act of 1935;
- Establishment of an Electric Reliability Organization under federal jurisdiction;
- Creation of Incentives to Promote Construction of New Transmission Facilities;
- Federal Backstop Siting for Interstate Electric Transmission Facilities; and

- Amendments to the Public Utility Regulatory Policies Act of 1978 designed to help encourage energy conservation, fuel diversity, and efficiency of new generation.

EPAct 2005 mandated that state regulatory authorities consider enacting rules, if they have not already done so in the previous three years, in the areas of net metering, interconnection, fuel diversity, efficiency of fossil fuel generation, and smart metering to enable new time-based rate designs. The Commission staff produced a white paper[1] on the matters requiring State consideration. The Commission concluded that its recently approved net metering (170 IAC 4-4.2) and interconnection (170 IAC 4-4.3) rules satisfy the requirements for consideration of two of the EPAct 2005 requirements. Consideration of the remaining three areas was initiated by a data request designed to draw on the jurisdictional utilities' current experience and thoughts on the topics. Responses to the request and the timelines established for each topic's consideration by EPAct 2005 drive the Commission's current focus on metering and communication to support time-differentiated pricing of electric services. The Commission anticipates rendering a decision regarding the appropriateness of instituting the federal standards in 2007.

Environmental Policy

In 2005-06, the U.S. Environmental Protection Agency ("EPA") finalized two new rules limiting the emissions from power plants in the eastern United States. The Clean Air Interstate Rule ("CAIR") mandates reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") emissions in two phases in order to help the eastern U.S. meet EPA's protective air quality standards for ozone or fine particles. The CAIR directs Indiana and other affected states to achieve the reductions by updating their existing State Implementation Plans ("SIPs"). The Indiana Department of Environmental Management is required to submit its rule for Indiana to the EPA by December 2006.

[1] Available at: http://www.in.gov/iurc/utilities/energy/epa/epa_index.html

The Clean Air Mercury Rule ("CAMR") limits mercury emissions from new and existing coal-fired power plants and creates a market-based cap and trade program that will reduce emissions in two phases. The Indiana Department of Environmental Management is developing the state rule to comply with CAMR and plans to submit it to the EPA in 2007.

Regional Transmission Organizations and Markets

On April 1, 2005, the Midwest ISO ("MISO") began operating both Day-Ahead and Real-Time energy markets to arrive at an optimal dispatch solution for all generation resources within its region. This enables the MISO to ensure that all load requirements in its region are met reliably and efficiently.

Activity in the MISO markets has been robust since market start-up. For the period April - December 2005, the MISO processed an average of $2.7 billion in energy transactions a month. For the period January - May 2006, the MISO processed an average of $2.2 billion in energy transactions each month.

In the first annual State of the Market report, the MISO market monitor concluded that the MISO energy markets have produced substantial savings since their inception. The benefits were substantially due to (1) daily coordinated commitment of generation, (2) improved generation dispatch and congestion management, (3) enhanced reliability, and (4) accurate price signals.

RTOs conduct long-term regional planning to identify system upgrade and expansion needs for reliability and, increasingly, for economic benefit. RTOs look at the needs across all of the utilities and loads within their region, and explore opportunities for inter-regional benefit. RTOs look at a wide range of transmission, generation and demand-side resource options to resolve reliability problems on the transmission system and to improve the economic performance of the bulk power system. The planning process encompasses a broad range of entities, including state regulators, consumer organizations

and others active in the regional power market. The result of this regional planning process are transmission expansion plans that are more cost effective and more transparent to all participants in the regional bulk power market.

MISO members have reported more than $673 million in transmission investment since 2001, including 2,017 miles of upgraded or new transmission lines. The PJM Interconnection has authorized nearly $2 billion of transmission system upgrades since 2000, of which $524 million has already been completed.

Both the MISO and PJM are taking actions to ensure that there will be adequate supply of electricity within their respective regions, and to improve the efficiency of their markets. The MISO is in the process of developing markets for ancillary services, and is also working on several more initiatives that may be enacted once the new ancillary service markets are operating. The PJM, with a majority of members operating in restructured states, has proposed a new approach for a generation capacity market in order to spur the building of new electric generation. The PJM proposal coordinates the price paid for generation capacity with overall PJM system reliability requirements. The proposal provides a process through which generation resources, transmission investments and demand-side resources directly compete in a four-year forward auction to satisfy system reliability requirements.

Commission Rulemakings

The Commission's ongoing interest in distributed resource issues resulted in the promulgation of a general rule to cover all interconnections between Indiana investor-owned electric utilities and their customers who wish to generate power with customer-owned generators. The rule was approved by the State of Indiana and became effective on April 5, 2006. The rule will make the interconnection process between utilities and customers more transparent and consistent across the state. Once the interconnection is complete, customers may be able use their generating resource to participate in demand response programs. In March of each year, the utilities will submit an annual report detailing the applications and interconnections for the previous calendar year.

Following informal activities, the Commission initiated a formal proceeding, Cause No. 42868, seeking to modify the form and maintenance of maps of assigned service areas established pursuant to Ind. Code §8-1-2.3-1. Representatives for each electric utility in Indiana joined in filing the petition on May 26, 2005. Currently the Commission utilizes a manual process based on pen and ink changes to the original Mylar maps created in the early 1980s. Technology advances provide more detailed, robust and user-friendly alternatives for consideration, such as computer-based mapping using Geographic Information Systems ("GIS") technology.

Several technical conferences attended by stakeholders aimed at implementing a working GIS format and converting the existing manual mapping system to be compatible. The Commission will house the GIS system and maps internally and provide web-based access to all electric service providers. Large and small utilities alike will have the on-line tool to propose and review future service area changes. The map conversion process is underway and full functionality is expected in January, 2007.

Merchant Plants in Indiana

Adequate generation capacity, low wholesale market prices and financial instability have affected the development of new generation capacity constructed, owned and operated by independent power producers. From March, 2001, to June, 2006, the Commission did not receive a new petition for the construction of a merchant plant facility. In June, 2006, a petition was filed for the construction of approximately 130 MW of wind generation in Benton County, Indiana.

I. NATIONAL ELECTRIC INDUSTRY ISSUES

A. ENERGY POLICY ACT OF 2005

In the summer of 2005, the U.S. Congress passed the Energy Policy Act of 2005 ("EPAct"), the first comprehensive national energy legislation in 13 years. The Act was signed into law by President Bush on August 8, 2005.

The Electricity Title has numerous provisions that could have major implications for the electric industry going forward. The status of some of these provisions is presented below:

1. **Repeal of the Public Utility Holding Company Act ("PUHCA") of 1935** – The EPAct repealed the PUHCA of 1935 and replaced it with the much narrower PUHCA 2005. PUHCA 2005 gives the Federal Energy Regulatory Commission ("FERC") access to the books and records of public utility holding companies and their affiliates and subsidiaries. It provides state commissions with access to books and records of a holding company if the state commission has jurisdiction to regulate a public utility company in the holding company system.

   Congress mandated that the FERC issue final rules to implement PUHCA 2005 by December 8, 2005, so that the rules would be in effect prior to the repeal of the 1935 act on February 8, 2006. On December 8, 2005, the FERC issued an order in Docket No. RM05-32-000 to finalize the rule.

2. **Establishment of an Electric Reliability Organization under FERC's Jurisdiction** – EPAct gives the Electric Reliability Organization ("ERO") the authority to set and enforce mandatory reliability standards for all users, owners, and operators of the bulk power system. It also requires the ERO to file proposed

standards with the FERC for its approval. The ERO must also perform periodic assessments of the adequacy and reliability of the bulk power system.

Congress required that FERC issue a final rule implementing this section no later than 180 days after the date of enactment. On February 3, 2006, the FERC issued an order in Docket No. RM05-30-000, implementing regulations that spell out the process for certifying a single independent ERO to propose and enforce a new national regime of mandatory reliability standards. On July 20, 2006, the FERC issued an order in Docket No. RR06-1-000 certifying the North American Electric Reliability Corp. as the nation's ERO.

3. **Creation of Incentive-Based Transmission Rates** – EPAct directed the FERC to develop by rule an incentive-based (including performance-based) rate structure for the transmission of electric energy in interstate commerce by public utilities, for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[2]

   The incentive-based rate structures considered by the FERC include the following:

   - Incentive rates of return on equity for new investment by public utilities
   - Full recovery of prudently incurred construction work in progress
   - Full recovery of prudently incurred pre-operation costs
   - Full recovery of prudently incurred costs of abandoned facilities
   - Use of hypothetical capital structures
   - Accelerated depreciation
   - Deferred cost recovery for utilities with retail rate freezes

[2] Transmission congestion occurs when transmission capacity is not sufficient to enable safe delivery of all scheduled or desired wholesale electricity transfers simultaneously.

Congress mandated that the FERC issue final rules to implement these incentive-based rate treatments no later than one year after enactment of EPAct. On July 20, 2006, the FERC issued an order in Docket No. RM06-4-000 that adopted the final rules.

4. **Federal Backstop of Siting for Interstate Electric Transmission Facilities** – EPAct directed the U.S. Department of Energy ("DOE") to conduct a study of electric transmission congestion. Based on that study, the Secretary of Energy may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor. DOE issued its report August 2006. The report will be effective for a three year period and public comments must be submitted by October 10, 2006.

   The EPAct also authorized the FERC to act as a federal backstop for siting authority and issuing permits for construction of certain transmission facilities in a designated national interest transmission corridor, in order to increase transmission capacity and maintain system reliability. The backstop authority can be exercised if (1) a state regulator does not have siting authority; or (2) the state regulator does not consider interstate benefits; or (3) the state regulator has withheld approval for more than one year after the latter of the filing of an application or the designation as a national interest electric transmission corridor; or (4) the state regulator conditioned its approval in such a manner that there will be no significant reduction in congestion.

   Congress mandated that the FERC issue rules specifying the form and information contained in the application for permitting, and the manner of service of notice of the permit application on interested persons. Congress did not specify a time by which the FERC rulemaking process was to be completed, but the FERC issued a proposed rule on June 15, 2006, in Docket No. RM06-12-000.

5. **Amendments to the Public Utility Regulatory Policies Act of 1978 ("PURPA")** – Which create for state commission consideration five new standards under PURPA to provide for:
    - Net metering – if adopted would require each electric utility to make available upon request net metering services to any electric consumer that the electric utility serves.
    - Smart metering – if adopted would require each electric utility to offer each of its customer classes, and provide individual customers on their own requests, a time-based rate schedule.
    - Interconnection – if adopted would require each electric utility to make interconnection service available on request to any electric customer with an on-site generation facility that wants to connect the generation facility to the local distribution system.
    - Fuel diversity – if adopted would require each electric utility to develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies.
    - Fossil fuel efficiency – if adopted would require each electric utility to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

    The standards are designed to help encourage energy conservation, fuel diversity, and efficiency of new generation. *Responsibility for consideration and determination of the five new PURPA standards falls on state commissions*. The Commission's response to these new PURPA requirements is discussed below in the section titled "IURC Rulemakings and other Related Matters."

B. FEDERAL ENVIRONMENTAL POLICY

In 2005-06, additional environmental rules were adopted which will require an industry response and development of aggressive contaminant reduction strategies. These rules

can be expected to have an impact on future rates, as companies make the investments required to achieve the new standards.

Clean Air Interstate Rule ("CAIR")

On March 10, 2005, the U.S. Environmental Protection Agency ("EPA") announced the Clean Air Interstate Rule, a rule which mandates reductions in sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emissions in order to help over 450 counties in the eastern U.S. to meet EPA's protective air quality standards for ozone or fine particles. SO_2 emissions contribute to the formation of fine particles, while NOx emissions contribute to the formation of fine particles and ground-level ozone. This rule and its requirements are closely tied to the Clean Air Mercury Rule, also announced in March 2005 and discussed below.

The CAIR directs the affected states to achieve the reductions by updating their existing State Implementation Plans ("SIPs"). CAIR contains a provision that allows states to participate in a cap and trade program to achieve the reductions. A cap and trade program involves the setting of a cap on the amount of a pollutant that can be emitted. Those companies or other emitters covered under the rule are given credits or allowances which represent the right to emit a specific amount. The total amount of credits cannot exceed the cap, limiting total emissions to that level. Companies that pollute beyond their allowances must buy credits from those who pollute less than their allowances. This scheme is thought to be much more cost effective at achieving given reductions versus other methods, because it allows a market to determine the most cost-effective reductions.

CAIR reductions have two phases: In the first phase, permissible SO_2 emissions will be reduced by 4.3 million tons by 2010, representing a 45% reduction from 2003 levels, while permissible NOx emissions will be reduced by 1.9 million tons by 2009, representing a 53% reduction from 2003 levels. By 2015, the second phase of CAIR will reduce SO_2 emissions by 5.4 million tons, representing a total reduction of 57% from 2003 levels, while NOx emissions will be reduced by 2 million tons, representing a 61%

reduction from 2003 levels. At full implementation, SO_2 emissions in the affected states will be 2.5 million tons (compared to 15.7 million tons in 1990); and NOx emissions will be 1.3 million tons (compared to 6.7 million tons in 1990).

The Indiana Department of Environmental Management ("IDEM") is required to submit its rule for Indiana to the EPA by December 2006. The IDEM Office of Air Quality has developed a Utility Rules Workgroup[3], which meets regularly to discuss the CAIR and the mercury rule. The IDEM CAIR rulemaking is on schedule to be concluded by the federal deadline.

Clean Air Mercury Rule ("CAMR")

On March 15, 2005, the EPA issued the Clean Air Mercury Rule, first federal rule to permanently cap and reduce mercury emissions from coal-fired power plants. The CAMR establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap and trade program that will reduce emissions in two phases. The first phase, effective in 2010, establishes a cap of 38 tons of mercury (compared to approximately 48 tons currently). These emission reductions will be substantially or wholly achieved through "co-benefits"—meaning that the technologies applied to reduce NOx and SO_2 for the CAIR will also reduce mercury emissions.

The second phase of the CAMR is effective in 2018, with a limit of 15 tons of mercury across the industry. IDEM began the mercury rulemaking for Indiana by publishing a First Notice of Comment Period in the June 1, 2005 Indiana Register.[4] IDEM will submit the final state rule to the EPA in the first half of 2007. The cap and trade program creates a mercury budget for each of 52 affected states and tribes. The budget for Indiana for 2010-2017 is 2.098 tons (compared to current estimated annual emissions of 2.5 tons) per year, a 15% reduction from 2002 levels. The budget for 2018 and beyond is 0.828 tons, a 66% reduction from 2002 levels. The budget levels are permanent, regardless of

[3] http://www.in.gov/idem/programs/air/workgroups/mercury/index.html

[4] http://www.in.gov/legislative/register/June-1-2005.html

whether additional coal-fired power plants are built in Indiana. Thus, any new plants would need to obtain mercury allowances from the market or other sources (such as a plant retirement) in order to operate.

Several states and environmental groups have sued the EPA in federal court over the rule. They argue that EPA has violated a provision of the Clean Air Act, which requires utilities to use the best-available technologies to reduce their mercury emissions. In addition, many of the same parties, under another part of the Clean Air Act, asked the EPA to reconsider CAMR. On October 21, 2005, the EPA granted a reconsideration of certain aspects of the rule, including the legal issues underlying the rule. After considering the issues and the additional public comments filed, on May 31, 2006 the EPA reaffirmed the original rule.[5] Indiana utilities are preparing to meet the 2010 phase one cap, although the rule is being challenged in federal court. In June 2006, sixteen states filed a petition in federal court to reactivate the 2005 lawsuit against the CAMR. The lawsuit had been put on hold during the reconsideration of the rule. IDEM is developing the state rule to comply with CAMR and plans to submit it to the EPA in 2007.

Indiana Utility Environmental Compliance Plans

Indiana electric utilities have begun to plan and prepare their systems for compliance with the recently issued CAIR and CAMR environmental mandates. Indianapolis Power & Light ("IPL"), PSI Energy ("PSI") and Southern Indiana Gas & Electric Co. ("SIGECO") have received approval from the Commission of their individual compliance plans.

These environmental compliance plans and associated cost recovery are addressed in various Indiana statutes; Ind. Code §8-1-8.7 governs the issuance of a Certificate of Public Convenience and Necessity ("CPCN") for the construction of Clean Coal Technology ("CCT"); Ind. Code §8-1-8.8 directs the Commission to encourage clean

[5] The EPA did make a few minor technical changes to the rule.

coal projects through the application of financial incentives and timely recovery of costs associated with such projects; and Ind. Code §8-1-2-6.6 and 6.7 discuss ratemaking treatment for CCT. These statutes encourage the use of Illinois Basin coal through the installation of CCT equipment, allowing utilities to earn a return of and on such investments without requiring a normal rate case proceeding, and allowing extraordinary ratemaking treatment.

The primary methods utilized for reducing the quantity of SO_2 discharged by coal-fired generation plants are (1) the installation of a Flue Gas Desulfurization system ("FGD" or "scrubber") on a unit, or (2) switching to a lower sulfur content coal to burn in a unit. Fuel-switching to comply with CAIR, if implemented at all, will likely be done at only the smallest generating units. Most generating units will require the installation of an FGD, which will enable Indiana coal to continue to be used to generate electricity. Popular methods for reducing NOx emissions by coal-fired generation are (1) the installation of Selective Catalytic Reduction equipment ("SCR") or (2) the use of advanced boiler equipment and programs aimed at reducing burn temperatures. Mercury emission reduction technology is less developed to date, but includes the use of equipment such as Activated Carbon Injection ("ACI") and Baghouse units. Additionally, mercury emissions are significantly reduced as a co-benefit of SCR/FGD combination installations. The reduced use of coal-fired generation through conservation or fuel switching could also reduce overall emissions of these pollutants.

1. Indianapolis Power & Light

IPL sought approval of modifications to its CPCN, granted in Cause No. 42170, for construction of CCT projects; for ongoing review of CCT projects; for the use of qualified pollution control property; for ratemaking treatment of construction costs; and for depreciation and cost recovery treatment in Cause No. 42700, filed July 30, 2004.

IPL's requested plan modification increased approved construction costs by $182 million; consisting primarily of the addition of an FGD at its Harding Street Unit 7 and enhancements to the existing FGD on Petersburg Unit 3. The utility and the OUCC filed

a Stipulation and Settlement Agreement which endorsed the plan modification and included ratemaking treatment. This treatment authorized, among other things, IPL to earn a 7.7% rate of return on the new CCT projects, set a 6.11% annual depreciation rate for 18 years, and allowed for recovery of operation and maintenance costs following the placement of any project in-service.

The Commission granted IPL's requested plan modification along with the Stipulation and Settlement Agreement on November 30, 2004. IPL's latest update to their plan (filed June 21, 2006) shows a current estimate of capital costs of $218.5 million for NOx projects, and an additional $187.5 million for SO_2 and mercury projects.

2. PSI Energy (Duke Energy Indiana)

PSI Energy filed a petition on September 2, 2004, Cause No. 42718 (which was consolidated with Cause No. 42622), which requested approval of a proposed compliance plan to meet the above mentioned emission mandates. Hearings were held May 9 and 10, 2005. A settlement agreement between PSI, the PSI Industrial Group, and the Office of Utility Consumer Counselor was filed on December 9, 2005. The settling parties agreed that, with the exception of the Gallagher Station baghouses (which were dealt with separately) the capital equipment portion of PSI's Phase 1 CAIR/CAMR Environmental Compliance Plan should be approved. The Commission issued an order approving the settlement on May 24, 2006.

PSI's proposed plan included estimated construction costs of $1.16 billion; (composed primarily of 5 FGD additions, 2 FGD upgrades, and 2 common ACI-Baghouse installations). The settlement parties agreed on cost recovery for all of PSI's proposed Phase I projects, with the exception of the activated carbon injection component of the Gallagher baghouse project. The parties agreed upon the timely recovery of financing, construction, operation and maintenance costs, depreciation, and emission allowance costs. The parties also agreed to a 20-year depreciation rate for the Phase I projects.

3. Southern Indiana Gas & Electric Company (Vectren Energy Delivery of Indiana)

SIGECO filed a petition on May 16, 2005, Cause No. 42861, which requested approval of a proposed compliance plan to meet the new emission mandates. The petition outlined a compliance plan that included the addition of 1 FGD and 1 fabric filter. SIGECO estimated the capital cost of the projects at $110 million. A settlement agreement between SIGECO and the OUCC was filed on October 20, 2005. On December 5, 2005, a supplemental settlement agreement was filed with the addition of the Citizens Action Coalition as a party. The parties to the settlement agreements agreed that SIGECO's Phase I projects and plan be approved. They agreed to an 18-year depreciation period for the projects, and to a sharing mechanism of proceeds from the sale of SO_2 and mercury allowances, with customers receiving 90% of the proceeds and SIGECO retaining 10%. The Commission issued an order approving the settlements, and consequently SIGECO's Phase I plan, on February 22, 2006.

C. REGIONAL TRANSMISSION ORGANIZATIONS

Two-thirds of Americans live in regions where transmission systems are operated by Regional Transmission Operators ("RTOs") and Independent System Operators ("ISOs"). A RTO is an independent entity that oversees electric reliability throughout a geographic region, and is responsible for coordinating the wholesale electric transmission system in that region. When a utility company joins an RTO it must transfer operational control, but not ownership, of its transmission system to an independent entity. The dispatch of generation is the principal means by which the system operators manage the transmission system and keep the system within the physical limits for safe and reliable operation.

Centralized economic dispatch permits the generation resources throughout the regional transmission system to meet the demand for electricity at the lowest possible production costs. Economies can be gained through load diversity across the broader region, which makes possible more extensive use of lower cost generation anywhere in the region.

RTOs have been developing in the Midwest for several years. The IURC has followed and participated in the process and has reported on these activities in previous reports to the Indiana General Assembly.

Midwest Independent Transmission System Operator ("MISO")

The MISO was formed by transmission owners in 1996, and is based in Carmel, Indiana. MISO provides transmission services over 947,000 square miles with 98,600 miles of high voltage transmission lines, and stretches from Pennsylvania to Nebraska and from Tennessee to the Canadian province of Manitoba. The MISO's main responsibility is to ensure the safe and reliable transfer of power in the Midwest, and ensure fair access to the transmission system. The MISO has 590 employees and two control centers – one at the Carmel headquarters facility and the other in St. Paul, Minnesota. Indiana electric utility members of the MISO are: PSI Energy, IPL, SIGECO, Wabash Valley Power Association, Hoosier Energy, Indiana Municipal Power Agency and NIPSCO.

PJM

AEP is a member of the PJM, the MISO's counterpart throughout all or portions of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

MISO Energy Markets Performance since April 1, 2005 Start

On April 1, 2005, the MISO began operating both Day-Ahead and Real-Time energy markets to arrive at an optimal dispatch solution for all generation resources within its region. This enables the MISO to ensure that all load requirements in its region are met reliably and efficiently.

There are a number of unique challenges to supplying electricity: production must equal demand at all times since electricity cannot be economically stored; demand varies greatly over the course of a day, week, and season; the operating costs of different types of generating units vary greatly; and both expected and unexpected conditions on the transmission system affect which generating units can be used to serve load reliably. The

MISO and the PJM schedule and dispatch generation in their region using a security constrained economic dispatch ("SCED") methodology based on the prices and operating characteristics offered by generation owners in the region. SCED is an optimization process that takes into account the unique attributes of supplying electricity in selecting which generation facilities to operate. This results in the most economical use of resources at any given moment for the entire region, taking into account all transmission constraints, while ensuring that sufficient generation is dispatched[6] to meet the energy requirements of the region.

The Midwest is a highly integrated segment of the national power system, and experiences substantial flows of power among the states. These flows can cause congestion on the transmission system. Congestion occurs when a transmission facility is either loaded in excess of its engineering rating for reliable operation or would be in excess of its rating in the event of a contingency.[7] The primary means of relieving congestion is to change the output of generation at different locations on the system, redirecting the flow of power. This "redispatch" can be implemented through non-market procedures or market-based procedures.

Transmission Loading Relief ("TLR") is an administrative procedure to keep transmission facilities from exceeding their limits, and was used by the MISO as a primary means to control congestion prior to market start-up. TLRs do not consider the costs of changing generation or the costs of different redispatch options. The current market-based procedure used by the MISO relieves the constraint by sending generation owners price signals. These price signals, called Locational Marginal Pricing ("LMP"), consider both the impact of specific generators on the constrained facility and the cost to change the generation output.

[6] Dispatch means that operators must decide in real time the level at which each available generation facility should be operated.
[7] Contingency is an unexpected failure or outage of a power system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Uncoordinated, separate dispatches by individual utility companies in response to congestion will not produce the same result as region-wide dispatch coordinated by an RTO. The sum of stand-alone least-cost dispatches by utility companies will produce higher costs than a regional least-cost dispatch, where transmission constraints can be relieved by the dispatch of the most economical generation regardless of utility ownership.

Activity in the MISO markets has been robust since market start-up. For the period April - December 2005, the MISO processed an average of $2.7 billion in energy transactions a month. For the period January - May 2006, the MISO processed an average of $2.2 billion in energy transactions each month.

TLR activity has improved since market start-up. The number of megawatt-hours curtailed dropped dramatically under market operations. During the pre-market period April – December 2004, more than 956,000 MWhs were curtailed when TLRs were issued. With market operations for the April – December 2005 period less than 138,000 MWhs were curtailed, a reduction of more than 85%.

The improvement in TLR curtailments means that 818,000 MWhs of energy remained available to sell or serve native load which otherwise would not have been available. If this energy had been curtailed, the alternatives would have been at a higher cost to consumers. Assuming the higher cost alternatives were $10 per MWh more expensive, savings from reduced curtailments of transactions were $8.18 million. If the alternative sources were $25 per MWh more expensive, savings would equal $20.45 million.

In the first annual State of the Market report[8], the MISO market monitor concluded that the MISO energy markets have produced substantial savings since their inception.[9] These benefits are concentrated in the following areas:

[8] 2005 State of the Market Report the Midwest ISO, prepared by the Independent Market Monitor for the Midwest ISO (Potomac Economics), July 2006.

[9] The Market Monitor is an independent entity whose responsibility is to prevent the distortion of competitive outcomes in the MISO energy markets while avoiding unnecessary interference with

1. Daily coordinated commitment of generation – the coordinated commitment of generation achieved through the day-ahead market produces savings relative to the less efficient decentralized system by reducing the quantity of generation committed, and ensuring the most economic generation within the MISO "footprint", not just within a given company's service area, is committed.
2. Generation dispatch and congestion management – total dispatch costs are reduced by producing energy from the most economic resources across the region, employing the lowest cost redispatch options to manage congestion on the transmission system, and more fully and efficiently utilizing the transmission capability in the region. More fully utilizing the transmission capability means that lower cost generation can be used to displace higher cost generation.
3. Enhanced Reliability – reliability is improved because the 5-minute market-based dispatch used by the MISO provides more responsive and accurate control of power flows on the transmission system, compared to administrative TLR procedures relied on previously.
4. Accurate Price Signals – the prices produced by the energy market provide transparent economic signals to help guide short and long-term decisions by market participants and regulators.

Regionally Coordinated Planning of Transmission Expansion

RTOs conduct long-term regional planning to identify system upgrade and expansion needs for reliability and, increasingly, for economic benefit. RTOs look at the needs across all of the utilities and loads within their region, and explore opportunities for inter-regional benefit. RTOs look at a wide range of transmission, generation and demand-side resource options to resolve reliability problems on the transmission system and to improve the economic performance of the bulk power system. The planning process encompasses a broad range of entities, including state regulators, consumer organizations and others active in the regional power market. The result of this regional planning

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competitive market processes. MISO market participants might try to distort markets by withholding generation capacity, output, or facilities from the market, by excessively raising the price or changing their offers to supply, etc. The Market monitor tries to prevent these types of activities.

process are transmission expansion plans that are more cost effective and more transparent to all participants in the regional bulk power market.

1. MISO

The Midwest ISO Board of Directors has approved two Midwest ISO Transmission Expansion Plans ("MTEP"), the MTEP 03 in June 2003 and MTEP 05 in June 2005. MTEP 05 identifies (through its Baseline Reliability study), 615 planned or proposed facility additions or enhancements representing an investment of $2.91 billion through 2009.[10] This is substantially above the $1.96 billion that was estimated for the six-year period 2002-2007 in MTEP 03. MTEP 06 is expected to be approved in December 2006.

MISO members have reported more than $673 million in transmission investment in the MISO region since 2001. This has included 2,017 miles of upgraded or new transmission line.

Approximately 5,123 miles of transmission line upgrades are projected through 2009, which is about 4.6% of the 112,000 miles of line existing throughout the MISO area. Only about 1,836 miles of the 5,123 miles represent new transmission corridors.

2. PJM

Since its first regional transmission expansion plan in 2000, PJM has authorized nearly $2 billion of transmission system upgrades, of which $524 million has already been completed. The total includes $1.3 billion in reliability related upgrades and $533 million in projects to interconnect new generation facilities.

[10] Examples of projects include building entirely new transmission facilities along new corridors, upgrading transmission lines from one voltage to a higher voltage and replacing corresponding transformers and substations.

Efforts to Improve Market Performance

Both the MISO and PJM are taking actions to ensure that there will be adequate supply of electricity within their respective regions, and to improve the efficiency of their markets.

1. MISO

As required by the Federal Energy Regulatory Commission, the MISO has been working with stakeholders to develop a permanent resource adequacy requirements plan that considers: (1) the unique characteristics of the MISO market participants; (2) the MISO region's needs; and (3) the views of state regulators. The MISO believes that a multi-phase approach is the best course of action.

Currently the MISO operates a Day-Ahead Market for electricity, a Real-Time Market for electricity and a Financial Transmission Rights ("FTR") market. These markets are operated separately, and are designed to work together to provide the benefits of competition in the wholesale markets to market participants. In Phase I, the MISO plans to develop markets for the provision of two ancillary services – Contingency Reserves[11] and Regulation[12] - and integrate these new markets into the current energy markets. Phase II over a longer period of time would change how pricing is determined in the MISO operated energy markets, should a shortage of generation capacity ever develop.

A MISO study reported that coordinated commitment and dispatch of ancillary services with the MISO's energy markets could result in total annual gross benefits ranging from $113 to $208 million. The MISO also estimates that this implementation would require one-time costs of between $36 and $63 million, and on-going annual operating costs of between $8 and $20 million. The MISO believes that the introduction of markets for operating reserves and regulation services will encourage new market entrants, facilitate participation by dispatchable demand-side resources, and promote competition for these services.

[11] Contingency reserves represent unloaded generation capability available within ten-minutes to supply energy in response to a generation unit or transmission line contingency or other abnormal event.
[12] Regulation reserve represents generation capacity that can increase or decrease output on a four to twelve second basis in order to allow generation in an area to balance with load.

The MISO expects that it will be able to file detailed Phase I plans with FERC in the fall of 2006.

Phase II of the MISO's resource adequacy proposal consists of several broad pieces:

1. Demand response, the active participation by retail customers in electricity markets, enables customers to manage usage and control costs by seeing and responding to prices as they change over time. Enhanced demand-side response to market price signals can improve the efficiency of energy markets, mitigate price spikes and reduce the potential for entities to exercise market power. The MISO believes the most effective demand response programs would include real-time hourly prices to send optimal price signals.
2. Develop longer-term financial transmission rights ("FTRs") consistent with FERC initiatives.[13] The longer-term FTRs will enable market participants to more effectively establish congestion hedges associated with the delivery of energy from particular generation resources. Currently, the MISO only allocates FTRs on a one-year basis and a party cannot be assured of being able to obtain adequate FTR coverage to manage the costs of congestion for a longer period of time. It is expected that the availability of longer-term FTRs will encourage more companies to sign multi-year power purchase contracts or to build baseload generation facilities.
3. Facilitate the use of longer-term energy contracts by market participants. Contracts to deliver energy for more than one year can be effective tools to manage costs. Such longer-term contracts can also provide financial markets with more confidence regarding the economic viability of new generation facility investments which could increase investment in new generation facilities by reducing risks.

[13] Financial transmission rights are financial instruments whose values are determined by the transmission congestion charges that arise in the MISO's day-ahead energy market. FTRs provide a financial hedging mechanism to manage the risk of congestion in the day-ahead energy market. Holders of FTRs may be protected against paying congestion charges for power from specified generators or purchases at one location on the transmission system and power being used by customers at a different location on the transmission system, essentially the holder of the FTR receives a rebate of congestion charges.

4. MISO will continue to coordinate issues with neighboring RTOs and non-market regions such as the Tennessee Valley Authority.
5. The MISO plans to coordinate its resource adequacy plans with national resource adequacy standards and the requirements that are developed the Electric Reliability Organization and the Regional Reliability Organizations in the region.

The MISO expects that it will make its Phase II filing with FERC in 2007.

2. PJM

PJM has proposed a new approach for a generation capacity market that is called the Reliability Pricing Model ("RPM"). This model coordinates the price paid for generation capacity with overall PJM system reliability requirements. The RPM provides a process through which generation resources, transmission investments and demand-side resources directly compete in a four-year forward auction to satisfy system reliability requirements.

The RPM proposal features:

- a long-term price structure that will signal the need for investment in new supply and infrastructure;
- the ability of consumers who are able and willing to reduce their demand when needed, and the ability of those willing to build transmission, to compete with generation in supplying capacity;
- pricing of wholesale generation capacity that varies by location to take into account the ability of the transmission system to deliver electricity into an area;
- price signals that recognize the value of generating capacity above minimum requirements to maintain reliability and supply;
- the continued use of self-supply to meet capacity obligations;
- consideration of generator operating characteristics necessary to ensure reliability, such as the ability to track changes in electricity load and to start generation units within 30 minutes or less.

On April 20, 2006, the FERC issued an initial order on the RPM proposal in which it provided guidance on numerous issues raised by the proposal, and established further procedures to try to resolve the remaining issues.

On May 1, 2006, the PJM opened its ancillary service market for synchronized reserves and regulation so that demand response providers can fully compete to provide these services. Demand response involves reducing the use of electricity to meet regional power system needs rather than increasing the output of electricity.

Organization of Midwest ISO States ("OMS")

The OMS coordinates state participation in the MISO stakeholder advisory process; coordinates state input to FERC when possible; and facilitates the sharing of information and analysis of issues. Each state retains its existing authorities, but OMS provides a mechanism for collaboration, promotes an improved understanding of regional issues and helps the states to produce better decisions, especially with regard to capital investments for transmission expansion.

The OMS formulates positions through its work groups that participate in the Midwest ISO stakeholder meetings and discuss issues among themselves. The OMS currently has nine work groups: Congestion Management and FTR Allocation; Demand Response; Long Term Development and Governance; Market Monitoring and Market Power Mitigation; Market; Pricing; Resource Adequacy and Capacity Markets; Seams Issues; and Transmission Planning and Siting.

Recent activities of the OMS include:

- Filing comments with the FERC on MISO's resource adequacy proposal, Docket No. ER06-1112-000, July 14, 2006.
- Submitting a white paper to the MISO Board of Directors on MISO Cost Recovery and Budgeting, June 8, 2006.

- Filing comments with the FERC on FERC's long term transmission rights rulemaking, Docket No. RM06-8, March 13, 2006.
- Submitting comments with the U.S. Department of Energy on the activity to develop national electricity transmission corridors, March 6, 2006.
- Filing comments on FERC's transmission incentive pricing rulemaking, Docket No. RM06-4, January 11, 2006.
- Filing a Request for Rehearing of FERC's order rejecting a request by the MISO for an extension of Broad Constrained Area mitigation, Docket No. ER06-731-000, June 8, 2006.

Cause Nos. 42685 and 42962: Recovery of MISO Costs

On July 9, 2004, PSI, IPL, NIPSCO, and SIGECO ("Petitioners") filed a joint petition, initiating Cause No. 42685, seeking approval of certain changes in operations likely to result from their participation in day-ahead and real-time energy markets which were then being implemented by the MISO, and seeking a determination of the manner and timing of recovery of costs resulting from implementation of the MISO energy markets.

The costs the Petitioners sought to pass through to ratepayers can be categorized as charges billed by MISO to market participants or internal costs incurred by the Petitioners.

A final order was issued on June 1, 2005. The commission order authorized the transfer of control area operations tasks and responsibilities to the MISO, and also authorized the transfer of dispatch and energy market tasks and responsibilities to the MISO. The cost recovery determinations reflected the different statutory provisions that apply, depending on whether the costs are fuel or non-fuel related, and also took account of prior Commission determinations in other proceedings which affected the regulatory status of each Petitioner.

The final order also created a technical workshop forum to assist the implementation of the changes that continue with the MISO Day 2 energy markets. Three technical workshops were conducted.[14]

In response to the discussion during the third technical workshop, NIPSCO, SIGECO and IPL, filed a joint petition initiating Cause No. 42962, in which they sought resolution of any uncertainty regarding the fuel adjustment clause ("FAC") pass-through of MISO Day 2 market-related Revenue Sufficiency Guarantee ("RSG") credits and charges, and a Commission finding that inclusion of such credits and charges in the FAC application is appropriate.

The Commission issued its order in Cause No. 42962, May 4, 2006, approving a settlement agreed to by the joint petitioners and the OUCC regarding MISO Day 2 market-related credits and charges. In the order, the Commission approved the recovery of RSG costs in FAC proceedings, but held that only such costs as were incurred after December 9, 2005 could be recovered through the FAC.[15] The affected utilities on May 19, 2006, filed a Petition for Reconsideration of the holding that RSG costs incurred prior to December 9, 2005, were non-recoverable through the FAC.[16] That petition was denied on June 28, 2006.

[14] Technical workshops were held July 12, 2005, October 11, 2005, and November 29, 2005.
[15] The Commission decided that while the Joint Petitioners may request modification of the Order in Cause No. 42685 through a separate proceeding (Cause No. 42962), its approval of the Settlement Agreement in Cause No. 42962 can not be retroactively applied. Accordingly, the Commission said the Joint Petitioners could implement recovery through the FAC for the relevant costs incurred on or after December 9, 2005 (the date the Verified Petition was filed initiating Cause No. 42962).
[16] The Commission did allow the Joint Petitioners in Cause No. 42685 to defer recovery of MISO's Day-Ahead RSG and Real-Time RSG amounts. Nothing in the Order in Cause No. 42962 changed the ability of the Joint Petitioners to defer recovery of the RSG charges and credits incurred prior to December 9, 2005.

II. INDIANA ELECTRIC INDUSTRY DEVELOPMENTS

A. SIGNIFICANT DECIDED / PENDING CASES

Cause Nos. 42643, 42658, 42824: Three Interrelated NIPSCO Cases

1. City of Gary's Request for the Valuation of NIPSCO'S Mitchell Plant Cause No. 42643

On May 7, 2004, the City of Gary petitioned the IURC to value NIPSCO's Mitchell Plant ("Mitchell"), a 500 MW coal-fired generating facility mothballed since June 2002, so that the city could exercise its right to acquire the property. The City of Gary planned to use the Mitchell site for an expansion of the Gary/Chicago airport and for various other commercial, residential, and recreational projects. In order to value Mitchell, the City of Gary asked the Commission to take notice of the facility's current idled status and to take into account the environmental remediation necessary before development of the site could occur.

On November 29, 2004, the City of Gary and NIPSCO filed a Joint Development and Marketing Agreement ("JDMA") with the Commission. The JDMA called for NIPSCO and Gary to cooperate in pursuing governmental or alternative funding for the demolition of the structures currently located at the Mitchell site, and for potential environmental remediation costs. The JDMA stated that no demolition or remediation costs would be borne by NIPSCO, its customers, or its parent company. The JDMA also stated that if governmental or alternative funding were sufficient to cover demolition and remediation costs, then NIPSCO would transfer the Mitchell site to Gary for a nominal value.

Evidentiary hearings in this Cause were held in mid-February 2005. On March 31, 2005, NIPSCO and the OUCC filed a Memorandum of Understanding ("MOU") with the Commission; pending the outcome of a study underpinning the MOU, NIPSCO and the OUCC expected the development of a formal settlement agreement resolving the issues

of this cause and Cause No. 42658. On July 14, 2005, the OUCC filed a Notice of Disavowal of the MOU. On September 8, 2005, NIPSCO filed a notice of settlement agreement ("3 Party Agreement") among NIPSCO, the OUCC, and the NIPSCO Industrial Group. The 3 Party Agreement: (1) accepted the JDMA reached in this cause between NIPSCO and the City of Gary; (2) resolved the issues of Cause No. 42643 and Cause No. 42658; and (3) partially resolved the issues in Cause No. 42824. The 3 Party Agreement was not formally filed for Commission consideration in this or any other cause, but was included for informational purposes in filings in Cause No. 42824 and Cause Nos. 38706-FAC68-FAC70.

In its January 18, 2006, Order, the Commission dismissed this Cause without prejudice. The Commission reasoned that the JDMA between NIPSCO and the City of Gary did not represent a valid contract, but rather an agreement to agree. The Commission made this determination based on its confirmation that: (1) the parties, or at least NIPSCO, did not view the JDMA as a final, binding agreement, and (2) the terms and details of the JDMA had not been fully defined by the parties. Consequently, the JDMA was not deemed to be ripe for consideration by the Commission.

2. NIPSCO'S Request for a Purchased Power & Transmission Tracker Cause No. 42658

On May 25, 2004, NIPSCO petitioned the Commission for approval of a purchased power and transmission tracker ("PPTT"). NIPSCO plans to use the PPTT to track power purchase costs incurred to fill current capacity deficiencies in intermediate dispatchable power ("IDP") and to track costs incurred by taking transmission service as a MISO member. NIPSCO plans to use the PPTT to flow through all charges relating to purchased power and transmission, as described above, including demand charges, capacity charges, energy charges, brokerage commissions, transmission costs, MISO charges, and the cost of options and physical derivatives acquired to manage risks associated with purchased power and transmission.

Hearings in this Cause concluded in early December 2004. On March 31, 2005, NIPSCO and the OUCC filed a Memorandum of Understanding ("MOU") with the Commission;

pending the outcome of a study underpinning the MOU, NIPSCO and the OUCC expected the development of a formal settlement agreement resolving the issues of this cause and Cause No. 42643. On July 14, 2005, the OUCC filed a Notice of Disavowal of the MOU. On September 8, 2005, NIPSCO filed a notice of settlement agreement ("3 Party Agreement") among NIPSCO, the OUCC, and the NIPSCO Industrial Group. The 3 Party Agreement: (1) accepted the JDMA reached in Cause No. 42643 between NIPSCO and the City of Gary; (2) resolved the issues of Cause No. 42643 and Cause No. 42658 (the 3 Party Agreement called for the withdrawal of NIPSCO's petition in this cause); and (3) partially resolved the issues in Cause No. 42824. The 3 Party Agreement was not formally filed for Commission consideration in this or any other cause, but was included for informational purposes in filings in Cause No. 42824 and Cause Nos. 38706-FAC68-FAC70.

On May 23, 2006, in Cause No. 42824, NIPSCO, Whiting Clean Energy, EnergyUSA-TPC, and the LaPorte County Board of Commissioners ("LaPorte") submitted for approval, a settlement agreement ("LaPorte Agreement") with the Commission. The LaPorte Agreement addresses the outstanding issues in Cause No. 42824, and calls for the dismissal of Cause No. 42658 and Cause No. 38706-FAC68-S1. Settlement hearings were held in Cause No. 42824 on June 19, 2006, and a final order was issued on August 23, 2006. The order approved the settlement agreement, resulting in the dismissal of Cause No. 42658 and Cause No. 38706-FAC68-S1.

3. NIPSCO Request for Authority to Purchase Power from Whiting Clean Energy via EnergyUSA-TPC Cause No. 42824

On April 11, 2005, NIPSCO, Whiting Clean Energy, and EnergyUSA-TPC (Collectively "Petitioners"[17]) petitioned the Commission for approval of a purchase power agreement ("PPA") whereby Whiting Clean Energy would sell power to EnergyUSA who would in turn sell said power to NIPSCO. The Petitioners claimed that NIPSCO urgently needed the intermediate dispatchable power ("IDP") that Whiting provided in order to reverse NIPSCO's declining performance against the North American Reliability Council's

[17] NIPSCO, Whiting Clean Energy, and EnergyUSA-TPC are affiliate companies owned by NiSource Inc.

CPS1[18] and CPS2[19] standards. In order to have the IDP available to NIPSCO for the summer months, the Petitioners requested that the PPA be approved, on at least an interim basis, by June 30, 2005, with full hearings on this matter at a later date. As part of its approval, the Petitioners requested that the Commission make certain PUHCA findings that would allow Whiting Clean Energy to maintain its status as an exempt wholesale generator. Issues such as cost recovery and NIPSCO's need for IDP were to be withheld until later full hearings. The Petitioners filed the MOU reached in Cause Nos. 42643 and 42658, as it addressed a study to be performed affirming NIPSCO's need for IDP and cost recovery of IDP resources.

An interim order was issued on July 1, 2005. In its order the Commission gave NIPSCO the authority to purchase power, on an interim basis, from Whiting Clean Energy through Whiting's cost based, FERC approved tariff. The Commission stated that approving the PPA, even on an interim basis, would be premature without full hearings in this cause, and may be viewed as a prejudgment of the issues raised in Cause Nos. 42643 and 42658. Therefore, the Commission decided to not make the requested PUHCA findings in its interim order. Full hearings in this cause were scheduled for fall 2005.

On August 22, 2005, the Petitioners filed, for informational purposes, a settlement agreement ("3 Party Agreement") reached among the Petitioners, the OUCC, and various NIPSCO industrial customers partially resolving the issues in this cause and resolving the issues in Cause Nos. 42643 and 42658. The 3 Party Agreement limited the monetary value of the purchases NIPSCO made under the PPA, as well as the amount and timing of IDP purchases. The 3 Party Agreement allowed NIPSCO to recover fuel and variable operation and maintenance expenses, by way of FAC proceedings, charged to it by Whiting for the production of IDP power. The 3 Party Agreement also called for NIPSCO to file a rate case petition on or before July 1, 2008.

[18] CPS1 is a measurement of how well each control area ("CA") supports the interconnection frequency. A measurement of 100% means the CA is adjusting its generation in a manner that meets its minimum obligation to maintain the interconnection's scheduled frequency.

[19] CPS2 is designed to limit the magnitude of unscheduled interchange. In order to comply with CPS2, each CA must keep its area control error within bounds, as determined by ECAR, 90% of the time each month.

Prior to the start of the hearings on April 24, 2006, counsels for Petitioner and LaPorte informed the presiding officers that the two parties were working toward a settlement agreement and asked that the hearings be continued. The parties' request was granted, and, subsequently, a settlement agreement ("LaPorte Agreement") between Petitioners and LaPorte was submitted for approval on May 23, 2006. The LaPorte Agreement calls for NIPSCO to return approximately $2.0 million of the approximately $5.0 million in incremental costs collected from NIPSCO's ratepayers for IDP purchases. $1.5 million of the return is slated to be credited to NIPSCO's ratepayers through the FAC process, while $0.5 million is earmarked for LaPorte's attorneys' fees. The LaPorte Agreement also calls for the dismissal of Cause Nos. 38706-FAC68-S1 and 42658. A settlement hearing was held in this cause on June 19, 2006, and a final order was issued on August 23, 2006. The order approved the settlement agreement, resulting in the dismissal of Cause No. 42658 and Cause No. 38706-FAC68-S1.

Cause No. 42873: Duke Energy / Cinergy Merger

On June 15, 2005, PSI Energy, Inc. filed a petition seeking the following relief related to the impending merger of Cinergy Corp. and Duke Energy Corp.: (1) approval to share a portion of net merger savings with its retail electric customers, and to defer certain merger-related costs; (2) approval of new service agreements and other affiliate agreements; (3) opening a sub-docket to consider revisions to PSI's affiliate guidelines; (4) approval for PSI to continue to maintain certain books and records outside of the State of Indiana; and (5) a finding that the merger would not adversely impact PSI's customer service, reliability, rates, financial integrity, or other relevant performance. Parties intervening in this Cause included: International Brotherhood of Electrical Workers, Local Union No. 1393; Wabash Valley Power Association, Inc.; Steel Dynamics, Inc.; Nucor Corporation; Hoosier Rural Electric Cooperative, Inc. ("Hoosier"); Citizens Action Coalition of Indiana, Inc. ("CAC"); and PSI-Industrial Group ("PSI-IG"). Additionally, the OUCC and certain designated members of the IURC staff ("Testimonial Staff") were parties to this Cause.

The proposed merger would create one of the largest combined electric and gas companies in North America, with approximately $36 billion in market capitalization, assets totaling more than $70 billion, and approximately 5.5 million gas and electric customers in Ohio, Kentucky, Indiana, North Carolina, South Carolina, and Ontario, Canada. The proposed merger called for an all-stock transaction at the holding company level, whereby Cinergy's shareholders would receive 1.56 shares of 'New Duke Energy' common stock for each share of Cinergy common stock owned, amounting to a 13.4% premium for Cinergy shareholders based on Cinergy's and Duke's stock prices immediately prior to the May 9, 2005, merger announcement. The Commission reviewed the merger's impact on PSI's retail customers.

On December 15, 2005, a signed settlement agreement ("Agreement") among PSI, the OUCC, Testimonial Staff, and the PSI-IG was submitted to the Commission. Of the intervening parties that were not a party to the Agreement, only the CAC filed testimony in opposition to it in this Cause. Some of the financial highlights of the Agreement include: a $40 million retail electric rate credit; a $5 million community contribution split evenly between the Indiana Center for Coal Technology Research and the Low Income Home Energy Assistance Program; preclusion of recovery of merger transaction costs from Indiana retail electric customers; and a reduction in PSI's retail electric rates of $11.552 million dollars annually, beginning June 1, 2008, for the removal of costs associated with the 1994 merger between PSI and the Cincinnati Gas & Electric Co. As a balance to these provisions, PSI will be allowed to retain merger savings in excess of the rate credit and the community contributions, subject to the FAC earnings test.

The Agreement also addresses service reliability and quality, and affiliate standards and agreements:

- Service reliability and quality: The Agreement calls for PSI to file quarterly reports with the Commission on its actual performance versus benchmarks on reliability and quality indices (SAIFI, SAIDI, CAIDI, Average Speed of Answer). Exceeding two or more benchmarks during the first five years following the

merger will require PSI to implement a Commission-approved remediation plan at a cost of up to $5 million. If PSI closes or moves the Plainfield Call Center out of the State of Indiana within three years of the merger, PSI is required to provide 30 days advance written notice to the Commission and Settling Parties and contribute $500,000 to the Indiana Economic Development Corporation or a successor fund.

- Affiliate standards and agreements: The Agreement directs PSI to follow the Affiliate Standards set forth in Attachment 2 to the Agreement, and provides for Commission approval of five affiliate agreements filed by PSI with its case-in-chief in this Cause. To ensure compliance with the Affiliate Standards, PSI agreed to fund and cooperate in a series of four independent audits of its compliance, including an audit of the Affiliate Standards training and controls PSI has in place to prevent cross-subsidization of its affiliates.

Finally, the Agreement covers PSI's future obligations for integrated resource planning, the methodology to be used for future cost of service studies and rate design for production plant, and the coordination of regulation between IURC and FERC orders concerning this Cause. In addition to the other specific provisions of the Agreement, PSI agreed to 42 additional specific merger commitments ("Additional Commitments") that were included as an attachment to the Agreement.

As the only party offering testimony in opposition of the Agreement, the CAC raised several objections and concerns about the Agreement and the Additional Commitments, and recommended several additional measures which the CAC contended PSI should take to protect its ratepayers' interests in this merger.

On May 15, 2006, the Commission issued its order in this cause approving the Agreement, the Additional Commitments, and some of the 'bolt on' provisions offered by the CAC. The 'bolt-on' provisions further addressed issues such as PSI's future debt ratings, future dividend distributions to Duke Energy Corporation, future money-pool borrowings, non-utility asset investments, and affiliate credit defaults. In its order, the Commission stated that the Agreement provides a reasonable balancing of interests and

noted that the Commission continues to have jurisdiction over PSI, and therefore, retains the authority to address any issues that arise in the future.

Cause No. 42894: Duke Energy Indiana and Vectren's IGCC Study

Integrated Gasification Combined Cycle ("IGCC") is a promising technology that would allow the continued use of coal as a fuel source while meeting increasingly stringent environmental regulations.

On August 9, 2005, Joint Petitioners, PSI Energy d/b/a Duke Energy Indiana and Vectren Energy Delivery of Indiana, filed a petition seeking the deferral and subsequent recovery of the costs incurred in conjunction with an ongoing study of a potential IGCC plant consisting of a feasibility study, preliminary engineering and mid-level detailed engineering and project evaluation, all to be concluded before a decision to build the plant can be made.

An IGCC facility uses coal gasification to convert coal to a synthetic gas ("syngas"), and produces steam as a part of the process. The hot syngas is processed to remove sulfur compounds, mercury and particulate matter before it is used to fuel a combustion gas turbine generator. The heat from the exhaust gases from the combustion turbine is recovered to generate additional steam. This steam, along with that from the syngas process, then drives a steam turbine generator. Coal gasification has been utilized since the early 1900s for a number of purposes, and for power generation since the 1980s. IGCC projects have been constructed worldwide, including the Wabash River Coal Gasification Repowering Project in 1995 near Terre Haute, Indiana, and the Tampa Electric Project in 1996 in Florida.

Duke and Vectren are conducting this study of IGCC before making any final decision on committing to this technology for a proposed baseload generation unit. Duke and Vectren believe that the study is necessary and will benefit their customers even if an IGCC facility is ultimately not built.

On March 22, 2006, a settlement agreement between the Joint Petitioners and the Office of Utility Consumer Counselor was filed. The settlement agreement set limits on the study costs that could be recovered from customers and outlined how costs would be shared between the joint petitioners and between shareholders and customers under various possible outcomes from the study. Intervening parties, Citizens Action Coalition and Indiana Industrial Customers, did not sign the settlement agreement.

On May 16, 2006 an evidentiary hearing was held. A final order approving the settlement agreement was issued by the Commission on July 27, 2006.

Alternative Regulation Plans ("ARP")

1. Cause No. 42966: PSI GoGreen Plan

On December 16, 2005, PSI filed a petition requesting the Commission approve a Qualifying Facility Purchased Power Agreement ("PPA") with BGT Green Valley Energy Project, LLC ("BGT"). BGT intends to generate green power from the methane gas in an abandoned coal mine near Terre Haute, Indiana. The project is expected to generate 3.7 MWs of electricity by March 31, 2007, with the potential to increase production capacity in the future. PSI's petition relief request included recovery of costs through the quarterly fuel adjustment clause and through a revised Green Power Rider; and for approval of a revised voluntary Green Power Rider, including ARP flexibility.

The change to the Green Power Rider from a voluntary customer contribution program to an actual Green Power rate provides customers the opportunity to purchase renewable energy credits and carbon credits through their payment of a kWh adder. PSI requested declination of Commission jurisdiction through an ARP to provide flexibility in pricing and participation in the GoGreen Power Program and in adjusting the size of the Green Power kWh blocks to be marketed. Commercial and Industrial customers are also permitted to participate in the GoGreen Power Rider on a customer-specific special contract basis.

The Commission approved the proposal on March 22, 2006 and identified potential benefits to be derived from implementation of PSI's proposed GoGreen Power Program: (1) the environment benefits by BGT's and others' generation of clean energy; (2) the BGT Project helps eliminate harmful methane gas; (3) customer awareness of green power and participation in the green power marketplace should increase, which can in turn drive demand for and investment in new green power renewable generation; and (4) as interest and participation in the renewable energy market grows, Indiana's economy stands to potentially benefit as additional renewable energy projects create new employment opportunities, perhaps even in the manufacturing sector.

2. Cause No. 42721: PSI Fixed Bill Plan

On September 16, 2004, PSI filed a Petition requesting the Commission decline its jurisdiction over, or otherwise approve, an alternative regulatory plan for the offering of a Fixed Bill Program, Your FixedBill, applicable to residential electric customers. Your FixedBill is a voluntary billing option which provides residential customers with the convenience and certainty of knowing they will pay the same amount each month for twelve (12) consecutive months regardless of the impact of weather, usage, or price fluctuations and without any end-of-period reconciliation or true-up. The monthly price of the Your FixedBíll optional billing product will be marketed to customers in a side-by-side comparison with the cost of regulated monthly bills under standard tariff pricing and budget billing.

The Commission approved the ARP on August 3, 2005 and found that providing voluntary billing options which may be popular with PSI customers is a reasonable undertaking, and that the FAC and other rider processes adequately eliminate the effects to non-participating customers from the Fixed Bill Program. PSI will provide an annual report to the Commission, to include adequate information concerning the efficacy of the program. The Commission approved an initial implementation period of three years and

noted that this type of voluntary, competitive Fixed Bill offering, wherein the sponsoring entity assumes the risk of financial loss resulting from the provision of a fixed monthly utility bill, is an example of the type of alternative regulatory proposal contemplated by the ARP statute.

B. IURC RULEMAKINGS AND OTHER RELATED MATTERS

Net Metering Rulemaking (RM# 03-05)

Following an informal stakeholder process of workshops and written comments about a proposed net metering rule, the Commission published a proposed net metering rule in the April 1, 2004, Indiana Register. Net metering is an arrangement in which customer-owned generation is interconnected with the utility, so that energy can flow to and from the distribution grid and the customer is billed only for his net energy consumption. The net metering rule applies to all Indiana investor-owned electric utilities and directs each to provide the opportunity of net metering to residential customers and K-12 schools. The rule is intended to encourage small-scale renewable energy projects, allowing users a measure of energy independence without jeopardizing the safety, energy cost or service quality of others on the interconnected grid.

The rule became final on December 21, 2004 (codified as 170 IAC 4-4.2). Net metering tariffs for the five Indiana investor-owned electric utilities (including revisions to three existing tariffs) were approved in the spring of 2005. On March 1 of subsequent years, the utilities will report to the Commission the number, type and size of net metering facilities on their systems. The utilities reported the following information for 2005:

Utility	Total Number of Net Metering Customers and Facilities	Number, Size and Type of Net Metering Facilities
Indiana Michigan Power	**0**	**NA**
IPL	**2**	**2 solar 1.05 kW (total)**
NIPSCO	**0**	**NA**
PSI Energy	**14**	**10 are 1.8 kW solar 4 are 1.0 kW solar**
SIGECO	**0**	**NA**

Interconnection Rulemaking (RM# 05-02)

The second phase of the Commission's ongoing interest in distributed resource issues resulted in the promulgation of a general rule to cover all interconnections between Indiana investor-owned electric utilities and their customers who wish to generate power with customer-owned generators. A draft rule was circulated to stakeholders in late January 2005, and informal written comments were received and circulated in March 2005. A revised draft was approved by the Commission in July 2005, which started the formal rulemaking process. The rule was approved by the State of Indiana and became effective on April 5, 2006.

The interconnection rule establishes three levels of scrutiny for proposed distributed resource projects, based on the size of the project and other technical parameters. Level 1 is for projects of 10 kW or less; Level 2 for projects less than 2 MW; and Level 3 covers all other projects. The rule will make the interconnection process between utilities and customers more transparent and consistent across the state. Once the interconnection is complete, customers may be able use their generating resource to participate in demand response programs. In March of each year, the utilities will submit an annual report detailing the applications and interconnections for the previous calendar year.

EPAct05 Suggested State Standards

In the summer of 2005, the U.S. Congress passed the comprehensive Energy Policy Act of 2005 ("EPAct 2005"). The Act was signed into law by President Bush on August 8, 2005. Title XII of the Act is the Electricity Title. EPAct 2005 makes changes to the Public Utility Regulatory Policies Act ("PURPA", see page 11 above). Some of these changes mandate that state regulatory authorities consider enacting rules (if they have not already done so in the previous three years) in the areas of net metering, interconnection, fuel diversity, fossil fuel generation efficiency and time-based metering and communication.

The Commission staff produced a white paper (available on the IURC website: http://www.in.gov/iurc/utilities/energy/epa/epa_index.html) on the required state consideration areas and concluded that its recently approved net metering (170 IAC 4-4.2) and interconnection (170 IAC 4-4.3) rules serve as consideration of those areas. Consideration of the remaining three areas was initiated by a data request designed to draw on the jurisdictional utilities' current experience and thoughts on the topics. Responses to the request and the timelines established for each topic's consideration by EPAct 2005 drive the Commission's current focus to time-based metering and communication. The Commission anticipates rendering a decision regarding the appropriateness of instituting the legislative standards as proposed in 2007.

2005 Reliability Statistics

On March 1, 2005, Indiana's investor-owned electric utilities[20] submitted their first Electric Reliability Indices Report in compliance with 170 IAC 4-1-23(e). The 2005 report included data for 2002, 2003 and 2004. On March 1, 2006, the utilities submitted their 2005 data.

[20] PSI Energy, Indianapolis Power & Light, Vectren, Indiana Michigan Power and Northern Indiana Public Service Co.

The report includes data for System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI") calculated with and without major storm events. SAIFI is calculated by dividing the total number of customers experiencing service interruptions over a defined period (in this case one year) by the total number of customers served by the utility. This index indicates how often a customer is likely to experience a service interruption during the year.

SAIDI is calculated by dividing the total duration of service interruptions in hours or minutes over the period by the total number of customers served by the utility. This index indicates how long a customer could expect to be without service over the year.

CAIDI is calculated by dividing SAIDI by SAIFI. This index indicates, on average, the duration of each service interruption. Differing operating and maintenance procedures among utilities may skew the service interruption results, such that one utility may have more frequent service interruptions of shorter durations while another could have fewer interruptions of longer duration.

It is difficult to make direct comparisons among the utilities based on the indices. Each utility reported its indices with and without major events. Major events are storms or weather events that are more destructive than normal storm patterns. Each utility tends to define a "major event" slightly differently; therefore some utilities will capture more of their service interruptions in the "without" category than other utilities. Service territory geography, size and customer mix are also factors which make direct comparison of the indices among the utilities difficult.

Table 1 presents the indices for all service interruptions submitted by each utility and a composite set of indices derived from the group. Table 2 presents similar information, but the indices exclude major storm events.

- On average IPL customers can expect less than one service interruption per year usually lasting less than two hours. IPL reported no major storm events for 2005.

IPL has a compact service territory that is fully developed (no remote or rural areas that may hamper the restoration of service). It should also be noted that IPL was under a settlement agreement that set financial penalties for not meeting specified reliability criteria. The settlement agreement expired at the end of the first quarter of 2005.

- A major ice storm in January 2005 severely impacted I&M's service interruption duration index, increasing the average interruption time to over 18 hours. Excluding the storm event brings the interruption duration index more in line with previous years and the utility composite measure. Even including storm events, I&M customers are likely to experience less than two service interruptions per year.
- The Vectren service territory also experienced two major storm events in 2005 but improved upon last year's overall indices. Vectren's indices excluding major storm events were slightly better than the comparable utility composite indices.
- PSI reported four major storm events that increased the system average service interruption duration from 2004 although by only 27 minutes.
- NIPSCO reported no major storm events for 2005. Its indices excluding major storm events were slightly higher than for 2004 but within a consistent range for the 2002-2005 timeframe.
- On average, a customer of one of Indiana's investor-owned electric utilities experienced fewer than two service interruptions per year over the last four years. Under all weather conditions during 2005, electric service was interrupted for about 6.8 hours per customer, total for the entire year. The duration of a single service interruption was about five hours. In 2004, under all weather conditions, electric service was interrupted for about 4.6 hours per customer over the entire year. The duration of a single service interruption was about 3.3 hours. The increase in service interruption durations was driven, primarily, by the major storm events in the I&M service territory.

Table 1: Indices Including Major Events

Utility/Index	*2002*	*2003*	*2004*	*2005*
PSI				
SAIFI	1.57	1.58	1.66	1.59
SAIDI	170.0	201.0	255.0	282.0
CAIDI	109.0	128.0	153.0	177.0
IPL				
SAIFI	1.17	0.90	0.81	0.90
SAIDI	132.9	98.0	76.7	66.5
CAIDI	113.3	108.4	94.1	73.9
Vectren				
SAIFI	1.46	1.27	2.36	2.05
SAIDI	164.0	111.0	932.4	376.0
CAIDI	107.0	87.0	394.7	185.0
I&M				
SAIFI	1.68	1.56	1.42	1.31
SAIDI	930.6	594.2	291.4	1,131.6
CAIDI	553.5	380.2	204.7	863.0
NIPSCO				
SAIFI	1.41	1.65	1.38	1.24
SAIDI	542.4	498.0	314.4	258.0
CAIDI	384.7	301.8	227.8	208.0
Composite				
SAIFI	1.47	1.43	1.42	1.35
SAIDI	390.3	312.8	278.2	409.6
CAIDI	265.0	218.3	195.4	303.4

Table 2: Indices Excluding Major Events

Utility/Index	*2002*	*2003*	*2004*	*2005*
PSI				
SAIFI	1.36	1.22	1.21	1.27
SAIDI	134.0	127.0	124.0	138.0
CAIDI	98.0	103.0	102.0	109.0
IPL				
SAIFI	1.03	0.79	0.71	0.90
SAIDI	73.8	65.7	53.2	66.5
CAIDI	72.0	83.2	74.5	73.9
Vectren				
SAIFI	1.46	1.27	1.12	1.68
SAIDI	164.0	111.0	106.8	137.0
CAIDI	107.0	87.0	95.4	82.0
I&M				
SAIFI	1.124	0.952	1.248	0.997
SAIDI	179.1	128.5	194.1	170.7
CAIDI	159.3	135.0	155.6	171.1
NIPSCO				
SAIFI	1.15	1.45	1.24	1.24
SAIDI	196.2	350.4	238.2	258.0
CAIDI	170.6	241.7	192.1	208.0
Composite				
SAIFI	1.21	1.13	1.11	1.16
SAIDI	145.0	158.0	145.0	153.5
CAIDI	119.9	140.2	130.1	132.6

GIS/Service Area Mapping Update

A series of public workshops held in recent years focusing on electric utility service and reliability led the Commission to explore alternatives to the present service area mapping archive. Currently the Commission utilizes a manual process based on pen and ink changes to the original Mylar[21] maps created in the early 1980's. Technology advances provide more detailed, robust and user-friendly alternatives for consideration. The workshop participants brought their technical expertise to the discussion and provided a range of options which included computer-based mapping using Geographic Information Systems ("GIS") technology.

The Commission continued to explore the GIS option for synergies among the various non-electric utilities and the active programs already underway throughout Indiana via discussions with the electric utilities, GIS industry experts and providers, and the non-electric utilities in Indiana. These explorations led to the recent start of a docketed proceeding, Cause No. 42868, seeking to modify the form and maintenance of maps of assigned service areas established pursuant to Ind. Code §8-1-2.3-1. Representatives for each electric utility in Indiana joined in filing the petition on May 26, 2005.

The parties established an executive committee and have held several technical conferences aimed at implementing a working GIS format and converting the existing manual mapping system to be compatible. The Commission will house the GIS system and maps internally and provide web-based access to all electric service providers. Large and small utilities alike will have the on-line tool to propose and review future service area changes. The map conversion process is underway and full functionality is expected in January, 2007.

[21] Mylar is a trade name for biaxially-oriented polyethylene terephthalate polyester film, which is used for its high-tensile strength, chemical and dimensional stability. It is a strong archival material well-suited for maps.

C. MERCHANT PLANTS

The Indiana Utility Regulatory Commission received its first "merchant plant" petition in November 1998, following an early summer price spike in the wholesale power market. Unprecedented wholesale power prices again in the summer of 1999 encouraged the development of merchant plant projects across Indiana. Through March 2001, the IURC received a total of 26 petitions for what were categorized as merchant plant projects. On June 8, 2006, Benton County Wind Farm, LLC, filed a petition outlining their plans to construct approximately 130 MW of wind generation in Benton County, Indiana. The hearing in this case is scheduled for October, 2006.

Merchant plants are generating facilities constructed to sell electricity into the competitive wholesale generation market. The companies which construct merchant plants take the full risk of the cost of construction and operation, in contrast to traditionally-regulated utilities that build generating facilities with IURC approval and may then recover the cost through the regulated ratemaking process.

Petitioners for merchant plant projects requested that the IURC either find that the facilities were not public utilities under I.C. 8-1-2-1 or, in the alternative, decline jurisdiction over the construction and operation.

The IURC found that the petitioners were, in fact, public utilities under I.C. 8-1-2-1. However, the petitioners were not exercising any rights, powers or privileges of public utilities, such as eminent domain or public rights-of-way, and would not be selling electricity to retail customers or recovering any costs through state jurisdictional rate recovery. Because of these circumstances, the IURC in large part declined jurisdiction over the petitioners and their construction and operation of the proposed merchant plants.

Since the initial merchant plant petition in 1998, the electric utility industry, and the energy industry in general, has undergone some dramatic upheavals; including the collapse of Enron, blackouts in California, increasing natural gas prices, and the

development and implementation of regional transmission organizations. As a result only 10 of the 26 merchant plant projects (excluding the Benton County Wind Farm) that the IURC received petitions for were built and became operational.

Over the past few years, several of these completed projects have been purchased (in full or in part) by Indiana load serving utilities. See the following table for details.

Operational Merchant Plants

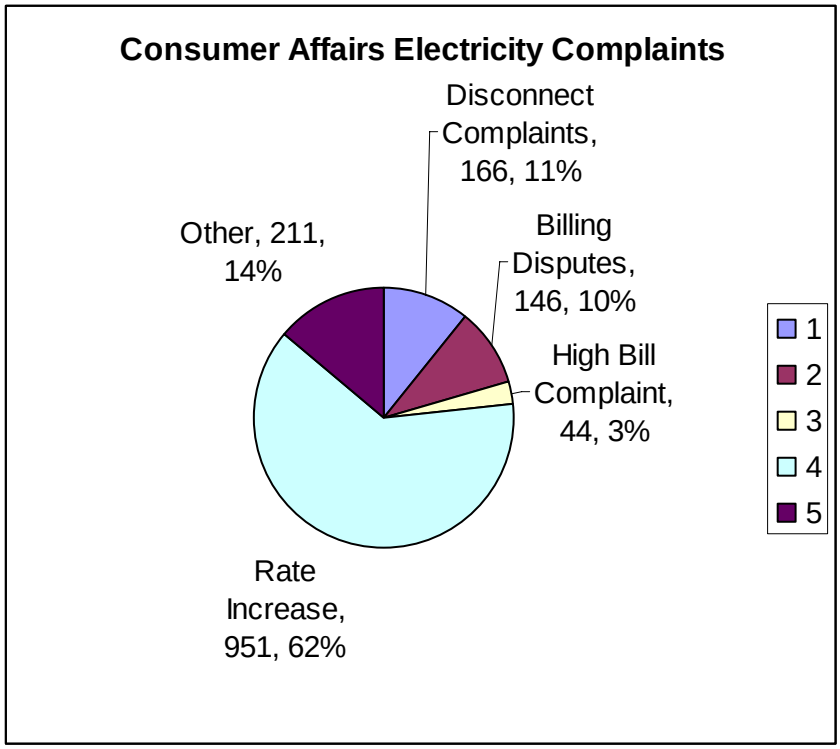
County	Name	Capacity	In Service Date	Ownership	Relevant Cause Nos.
Henry	Henry County Generating Station	135 MW	June 2001	Originally owner was CINCAP VII, LLC, a jointly owned subsidiary of Cinergy and Duke Energy. Ownership transferred to PSI Energy in December 2002.	41569 42145
Marion	Georgetown	80 MW	May 2000	IPL	41337
Vermillion	Duke Vermillion	640 MW	2000	Original owner Duke Vermillion LLC. 25% share transferred to Wabash Valley Power Association March 2004. Remaining 75% ownership transferred to CG&E February 2006.	41388 42495 42929
Knox	Wheatland LLC – formerly West Fork	Summer – 448 MW Winter – 508 MW	2000	Originally owned by Enron transferred to Allegheny May 3, 2001. Ownership transferred to Duke Energy Indiana (PSI) per IURC order August 3, 2005	41411 42469 42865 42866 consolidated
Marion	DTE Georgetown	240 MW (3-80 MW turbines)	June 2000	In August 2004 ownership of 2 of the 80 MW turbines was transferred to IMPA	41566 42455
Wells	DPL Generating Station	200 MW	June 2001	DPL Energy	41685
Lake	Whiting Clean Energy	525 MW	April 2002	Whiting is a wholly-owned subsidiary of NiSource. It supplies steam to adjacent Whiting Refinery	41530
Marion	Harding Street Station	151 MW	May 2002	IPL	42033
Vigo	Sugar Creek	300 MW	2002	Wholly-owned by Mirant	41753 42015
Dearborn	PSEG Lawrenceburg	1150 MW	Summer 2003	Ownership was transferred to Exelon in 2005	41757 42887

D. ROLE OF THE CONSUMER AFFAIRS DIVISION

The Consumer Affairs Division of the Commission mediates disputes between utilities and consumers and deals with consumer education issues. The division reviews and revises the "Rules, Regulations and Standards of Service" for the Indiana utilities. These rules must be followed by the utilities when dealing with their customers.

The division uses information gathered in the complaint handling process to alert the Commission to any consumer problems. If the office discovers a problem developing, it may request an investigation be conducted by the Commission or it may suggest to the utility's customers that they circulate a petition requesting a Commission investigation. The Consumer Affairs Division also attends Commission field hearings to answer any individual consumer questions or complaints that may arise during the hearing process.

The Consumer Affairs Division received 1,518 electricity complaints for the fiscal year of July 1, 2005 through June 30, 2006. 948 of these were due to consumers writing the Commission about PSI Energy's rate increase due to increased environmental costs. The majority of the remaining complaints were either billing disputes, complaints about a high monthly bill, or a service disconnect. The chart below displays a distribution of the complaints mentioned.


Consumer Affairs Electricity Complaints
Disconnect Complaints, 166, 11%
Billing Disputes, 146, 10%
High Bill Complaint, 44, 3%
Rate Increase, 951, 62%
Other, 211, 14%
1
2
3
4
5

III. INDIANA'S ELECTRIC INDUSTRY – STATISTICS

This section is a review of the energy sales, revenue, average price and market share for Indiana's electric utilities.

1. Investor-Owned Utilities

There are five investor-owned utilities operating in Indiana. These utilities are the most significant in terms of generation and in number of customers served. The five investor-owned utilities that operate within the state are:

Indianapolis Power & Light, a wholly-owned subsidiary of AES Corporation;

Indiana Michigan Power, wholly owned by American Electric Power;

Northern Indiana Public Service Company, a NiSource company;

PSI Energy, a wholly-owned subsidiary of Duke Energy; and,

Southern Indiana Gas & Electric Company, a subsidiary of Vectren Energy Delivery of Indiana.

2. Municipal Utilities

There are 72 municipally owned electric utilities in Indiana. As of July 2006, seventeen remain under IURC jurisdiction for rate regulation. Currently 49 municipals in the state are members of the Indiana Municipal Power Agency. IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA meets its members' needs through a combination of owned generating facilities, member-dedicated generation, and purchased power.

3. Cooperatives

There are thirty-nine electric distribution co-ops operating in Indiana. As of July 2006, four co-ops remain under Commission jurisdiction for rate regulation. Most of the distribution co-ops are members of either Hoosier Energy or Wabash Valley Power Association. These two organizations are generating and transmission cooperatives formed to supply power to distribution co-ops. Hoosier Energy and WVPA serve as coordinators of bulk power supplies and transmission services for their members.

Sales, Revenues and Market Share for Electric Utilities (2005)

MWH

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	23,566,119	17,715,885	38,903,955	2,504,733	82,690,692
Rural Electric Membership Corporations	1,069,466	1,002,182	NA	5,122	2,076,770
Municipal Utilities	1,362,905	3,311,783	NA	73,439	4,748,127
Totals	**25,998,490**	**22,029,850**	**38,903,955**	**2,583,294**	**89,515,589**

REVENUE (000s)

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	$ 1,691,006	$ 1,132,724	$ 1,666,412	$ 73,672	$ 4,563,814
Rural Electric Membership Corporations	$ 79,612	$ 48,746	NA	$ 1,249	$ 129,607
Municipal Utilities	$ 94,048	$ 181,973	NA	$ 8,729	$ 284,750
Totals	**$ 1,864,666**	**$ 1,363,443**	**$ 1,666,412**	**$ 83,650**	**$ 4,978,171**

RETAIL MARKET SHARE BY MWH

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	90.64 %	80.42 %	100.00 %	96.96 %	92.38 %
Rural Electric Membership Corporations	4.11 %	4.55 %	0.00 %	0.20 %	2.32 %
Municipal Utilities	5.24 %	15.03 %	0.00 %	2.84 %	5.30 %

RETAIL MARKET SHARE BY REVENUES

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	90.69 %	83.08 %	100.00 %	88.07 %	91.68 %
Rural Electric Membership Corporations	4.27 %	3.58 %	0.00 %	1.49 %	2.60 %
Municipal Utilities	5.04 %	13.35 %	0.00 %	10.44 %	5.72 %

Please note that REMCs and municipal utilities do not present separate commercial and industrial information in the annual reports they submit to the Commission therefore the summarized commercial and industrial data is shown under the "Commercial" heading on the tables.

Individual IOU Sales, Revenues and Market Share (2005)

MWH

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	5,985,598	5,089,628	8,089,655	83,319	19,248,200
Indianapolis Power & Light Company	5,314,160	2,076,006	7,663,476	83,458	15,137,100
Northern Indiana Public Service Company	3,516,122	3,893,017	9,131,609	114,970	16,655,718
PSI Energy, Inc.	9,069,635	5,910,619	11,639,028	2,242,477	28,861,759
Southern Indiana Gas & Electric Company	1,571,340	1,555,604	2,388,778	12,956	5,528,678
Totals	25,456,855	18,524,874	38,912,546	2,537,180	85,431,455

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	$ 396,739	$ 301,998	$ 345,853	$ 6,401	$ 1,050,991
Indianapolis Power & Light Company	$ 344,323	$ 147,091	$ 377,904	$ 11,162	$ 880,480
Northern Indiana Public Service Company	$ 349,918	$ 335,013	$ 445,061	$ 14,381	$ 1,144,373
PSI Energy, Inc.	$ 654,891	$ 347,116	$ 486,231	$ 122,032	$ 1,610,270
Southern Indiana Gas & Electric Company	$ 132,225	$ 100,426	$ 105,726	$ 2,087	$ 340,464
Totals	$ 1,878,096	$ 1,231,644	$ 1,760,775	$ 156,063	$ 5,026,578

AVERAGE RATE, CENTS PER KWH

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	6.63	5.93	4.28	7.68	5.46
Indianapolis Power & Light Company	6.48	7.09	4.93	13.37	5.82
Northern Indiana Public Service Company	9.95	8.61	4.87	12.51	6.87
PSI Energy, Inc.	7.22	5.87	4.18	5.44	5.58
Southern Indiana Gas & Electric Company	8.41	6.46	4.43	16.11	6.16

RETAIL MARKET SHARE

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	37.75%	28.73%	32.91%	0.61%	100%
Indianapolis Power & Light Company	39.11%	16.71%	42.92%	1.27%	100%
Northern Indiana Public Service Company	30.58%	29.27%	38.89%	1.26%	100%
PSI Energy, Inc.	40.67%	21.56%	30.20%	7.58%	100%
Southern Indiana Gas & Electric Company	38.84%	29.50%	31.05%	0.61%	100%

Regulated REMC Sales, Revenues and Market Share (2005)

MWH

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	344,001	181,138	3,123	528,262
Jackson County R.E.M.C.	400,163	81,771	72	482,006
Marshall County R.E.M.C.	76,006	19,876	1,492	97,374
Northeastern R.E.M.C.	323,592	752,374	1,054	1,077,020
Totals	1,143,762	1,035,159	5,741	2,184,662

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	$ 24,416	$ 9,861	$ 868	$ 35,145
Jackson County R.E.M.C.	$ 29,167	$ 5,073	$ 633	$ 34,873
Marshall County R.E.M.C.	$ 7,602	$ 1,765	$ 270	$ 9,637
Northeastern R.E.M.C.	$ 26,339	$ 43,341	$ 259	$ 69,939
Totals	$ 87,524	$ 60,040	$ 2,030	$ 149,594

AVERAGE REVENUE, CENTS PER KWH

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	7.10	5.44	27.79	6.65
Jackson County R.E.M.C.	7.29	6.20		7.23
Marshall County R.E.M.C.	10.00	8.88	18.10	9.90
Northeastern R.E.M.C.	8.14	5.76	24.57	6.49

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Harrison County R.E.M.C.	69.47%	28.06%	2.47%
Jackson County R.E.M.C.	83.64%	14.55%	1.82%
Marshall County R.E.M.C.	78.88%	18.31%	2.80%
Northeastern R.E.M.C.	37.66%	61.97%	0.37%

Regulated Municipal Sales, Revenues and Market Share (2005)

MWH

Utility	Residential	Commercial	Other	Totals
Anderson Municipal Light & Power	337,337	394,674	4,959	736,970
Auburn Municipal Electric	64,061	372,230	NA	436,291
Bargersville Municipal Light & Power	32,982	16,562	1,942	51,486
Columbia City Municipal Electric	38,723	67,137	2,592	108,452
Crawfordsville Municipal Electric Light & Power	6,173	18,428	327	24,928
Frankfort City Light & Power	80,609	282,731	2,787	366,127
Kingsford Heights Municipal Electric	5,864	NA	NA	5,864
Knightstown Municipal Electric	13,935	10,384	NA	24,319
Lawrenceburg Municipal Electric	29,528	113,827	7,626	150,981
Lebanon Municipal Electric	70,717	142,392	2,971	216,080
Logansport Municipal Electric	109,344	283,307	2,737	395,388
Mishawaka Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	206,715	734,266	11,442	952,423
Straughn Municipal Electric	NA	NA	NA	NA
Tipton Municipal Electric	40,352	78,655	998	120,005
Troy Municipal Electric	10,067	NA	NA	10,067
Totals	1,046,407	2,514,593	38,381	3,599,381

Note: "NA", or Not Available, because the utility did not file this information with the Commission in their annual report filing.

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$ 24,525	$ 24,431	$ 1,060	$ 50,016
Auburn Municipal Electric	$ 2,962	$ 18,591	$ 240	$ 21,793
Bargersville Municipal Power & Light	$ 2,413	$ 1,204	$ 267	$ 3,884
Columbia City Municipal Electric	$ 2,710	$ 4,323	$ 381	$ 7,414
Crawfordsville Municipal Electric Light & Power	$ 6,173	$ 18,428	$ 3,520	$ 28,121
Frankfort City Light & Power	$ 5,287	$ 13,220	$ 492	$ 18,999
Kingsford Heights Municipal Electric	$ 334	$ 145	$ 82	$ 561
Knightstown Municipal Electric	$ 866	$ 661	$ 42	$ 1,569
Lawrenceburg Municipal Electric	$ 1,647	$ 5,848	$ 246	$ 7,741
Lebanon Municipal Electric	$ 4,652	$ 8,265	$ 478	$ 13,395
Logansport Municipal Electric	$ 7,389	$ 15,404	$ 336	$ 23,129
Mishawaka Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	$ 14,955	$ 42,422	$ 17,088	$ 74,465
Straughn Municipal Electric	NA	NA	NA	NA
Tipton Municipal Electric	$ 2,794	$ 4,926	$ 109	$ 7,829
Troy Municipal Electric	$ 254	$ 439	$ 22	$ 715
Totals	**$76,961**	**$158,307**	**$24,363**	**$259,631**

Note: "NA", or Not Available, because the utility did not file this information with the Commission in their annual report filing.

AVERAGE REVENUE, CENTS PER KWH

Utility	Residential	Commercial	Other	Totals
Anderson Municipal Light & Power	7.27	6.19	21.38	6.79
Auburn Municipal Electric	4.62	4.99	NA	5.00
Bargersville Municipal Light & Power	7.32	7.27	13.75	7.54
Columbia City Municipal Electric	7.00	6.44	14.70	6.84
Crawfordsville Municipal Electric Light & Power	7.30	5.26	NA	5.68
Frankfort City Light & Power	6.56	4.68	17.65	5.19
Kingsford Heights Municipal Electric	5.70	NA	NA	9.57
Knightstown Municipal Electric	6.21	6.37	NA	6.45
Lawrenceburg Municipal Electric	5.58	5.14	3.23	5.13
Lebanon Municipal Electric	6.58	5.80	16.09	6.20
Logansport Municipal Electric	6.76	5.44	12.28	5.85
Mishawaka Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	7.23	5.78	149.34	7.82
Straughn Municipal Electric	NA	NA	NA	NA
Tipton Municipal Electric	6.92	6.26	10.92	6.52
Troy Municipal Electric	2.52	NA	NA	7.10

Note: “NA”, or Not Available, because the utility did not file this information with the Commission in their annual report filing.

RETAIL MARKET SHARE

Utility	Residential	Commercial	Other
Anderson Municipal Light & Power	49.03%	48.85%	2.12%
Auburn Municipal Electric	13.59%	85.31%	1.10%
Bargersville Municipal Light & Power	62.13%	31.00%	6.87%
Columbia City Municipal Electric	36.55%	58.31%	5.14%
Crawfordsville Municipal Electric Light & Power	21.95%	65.53%	12.52%
Frankfort City Light & Power	27.83%	69.58%	2.59%
Kingsford Heights Municipal Electric	59.54%	25.85%	14.62%
Knightstown Municipal Electric	55.19%	42.13%	2.68%
Lawrenceburg Municipal Electric	21.28%	75.55%	3.18%
Lebanon Municipal Electric	34.73%	61.70%	3.57%
Logansport Municipal Electric	31.95%	66.60%	1.45%
Mishawaka Municipal Electric	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA
Richmond Municipal Power & Light	20.08%	56.97%	22.95%
Straughn Municipal Electric	NA	NA	NA
Tipton Municipal Electric	35.69%	62.92%	1.39%
Troy Municipal Electric	35.52%	61.40%	3.08%

Note: "NA", or Not Available, because the utility did not file this information with the Commission in their annual report filing.

Generation Capacity by Utility (MW)

Utility	Summer
Indiana Michigan Power Company	5,042
Indianapolis Power & Light Company	3,301
Northern Indiana Public Service Company	2,787
PSI Energy, Inc.	7,503
Southern Indiana Gas & Electric Company	1,348
Hoosier Energy	1,140
Wabash Valley Power Association	414
Indiana Municipal Power Agency	726

Source: Responses to the 2006 IURC Annual Summer Capacity Survey.

Average Revenue per kWh by State (Ranked in Descending Order by Average Rate)

STATE	2004 Residential	2004 Average	2005 Residential	2005 Average	2006 Residential	2006 Average
Hawaii	17.10	14.94	18.82	16.45	22.87	20.39
Massachusetts	11.47	10.35	13.08	11.65	17.64	15.75
New Hampshire	12.10	11.13	13.11	12.10	14.83	14.27
Connecticut	11.76	10.55	13.01	11.51	15.95	14.02
Rhode Island	12.09	10.95	11.86	11.01	15.22	14.01
New York	13.78	11.29	14.38	11.83	16.21	13.11
Alaska	11.83	10.61	12.53	11.16	14.12	12.29
California	11.98	11.01	11.49	10.52	13.40	11.67
Vermont	12.67	11.02	12.92	11.09	13.33	11.36
Maine	12.59	10.48	12.86	9.95	14.25	10.83
New Jersey	10.68	9.50	10.55	9.70	11.34	10.41
Florida	8.76	8.03	9.43	8.59	11.15	10.32
Texas	8.66	7.18	9.61	7.95	12.02	9.87
Pennsylvania	9.02	7.88	9.37	8.00	9.95	9.37
District of Columbia	7.35	6.42	8.16	8.17	8.50	9.09
Nevada	9.08	7.83	10.22	8.32	10.93	8.81
Mississippi	7.33	6.43	7.99	6.88	9.64	8.38
Louisiana	7.45	6.71	7.83	7.05	8.97	8.37
Maryland	7.09	6.34	7.51	7.13	7.97	8.25
Michigan	8.31	6.91	8.37	7.19	9.63	8.02
Wisconsin	8.64	6.64	9.18	7.03	10.22	7.95
Colorado	8.00	6.73	8.74	7.27	9.21	7.89
New Mexico	8.36	6.94	8.67	7.11	9.01	7.50
Georgia	7.37	6.30	7.98	6.86	8.67	7.47
North Carolina	8.06	6.88	8.44	7.05	8.96	7.46
Ohio	7.83	6.61	7.97	6.78	8.85	7.45
Delaware	7.86	6.65	8.11	7.02	8.71	7.42
Arizona	7.46	6.88	8.15	7.22	8.34	7.32
Oklahoma	6.72	5.69	7.09	5.99	8.48	7.27
Iowa	8.14	6.00	8.78	6.24	9.43	6.82
Tennessee	6.76	6.12	6.85	6.16	7.46	6.78
Montana	7.28	5.87	7.62	6.50	7.92	6.74
South Carolina	7.52	5.97	8.35	6.42	8.86	6.73
Illinois	7.86	6.54	7.80	6.50	8.00	6.67
Virginia	7.43	6.29	7.72	6.46	7.98	6.63
Alabama	7.15	5.89	7.43	5.85	8.31	6.59
Minnesota	7.40	5.88	7.72	6.14	8.29	6.57
Oregon	7.11	6.29	7.20	6.32	7.42	6.52
Kansas	7.15	5.98	7.45	6.23	7.69	6.44

STATE	2004 Residential	2004 Average	2005 Residential	2005 Average	2006 Residential	2006 Average
South Dakota	6.94	6.25	7.18	6.36	7.35	6.35
Indiana	**6.76**	**5.35**	**7.17**	**5.64**	**7.99**	**6.30**
Arkansas	6.70	5.27	7.09	5.58	7.90	6.17
Utah	6.62	5.25	7.17	5.59	7.32	5.71
Wyoming	6.53	4.78	7.00	5.09	7.17	5.13
Missouri	6.27	5.43	6.33	5.53	6.69	5.64
Washington	6.40	5.81	6.45	5.78	6.68	5.96
Kentucky	5.67	4.34	6.15	4.56	6.62	4.94
North Dakota	5.95	5.36	6.18	5.51	6.50	5.71
Nebraska	5.91	5.18	6.17	5.35	6.46	5.54
Idaho	5.74	4.93	5.90	4.93	6.13	5.14
West Virginia	6.02	5.15	6.09	5.15	6.11	4.97
U.S. Average	**8.38**	**7.22**	**8.79**	**7.52**	**9.85**	**8.39**

Source: Energy Information Administration: "Electric Monthly Power" July 2006 (Table 5.6 B). 2005 and 2006 values are for year-to-date through April of each year, and include the residential, commercial, industrial and "other" sectors. The average is the revenue divided by the kwh sales.

IV. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Demand Response: Reducing the use of electricity to meet local or regional power system needs rather than increasing the output of electricity.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Energy Policy Act of 2005: This act was the first major energy policy legislation to become law in 13 years. It is over 1700 pages long and contains hundreds of provisions. Major provisions regarding the electricity industry included the creation of PUHCA 2005, clean coal, nuclear, wind, and alternative energy initiatives, establishment of an Electric Reliability Organization, incentive rates for transmission investment, transmission siting, smart metering, net metering, utility interconnection with distributed generation, increased efficiency of fossil-fuel power plants, and the increased diversity of fuel sources to generate electricity.

Federal Energy Regulatory Commission ("FERC"): The U.S. federal agency with jurisdictions over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also authorizes liquefied natural gas terminals, interstate natural gas pipelines and non-federal hydropower projects.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Grandfathered Agreements (GFAs): Transmission service agreements currently in force in the MISO region that were entered into prior to September 16, 1998

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Integrated Gasification Combined Cycle "IGCC": a power plant using synthetic gas as a source of clean fuel. Syngas is produced from coal (or other fuels) in a gasification unit. Steam generated by waste heat boilers of the gasification process is utilized to help power steam turbines.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Locational Marginal Pricing: The cost of delivering the next increment of power to a particular location, taking into account both the generation marginal cost and the physical aspects of the transmission system.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of power supplied to or taken from an electric circuit steadily for one hour.

Merchant Plant: A power plant that is funded by investors and sells electricity in the competitive wholesale market. Since a merchant plant is not required to serve any specific retail ratepayers, ratepayers are not obligated to pay for the construction, operations or maintenance of the plant.

MISO: The Midwest ISO was formed by transmission owners in 1996, and is based in Carmel, Indiana. The MISO's main responsibility is to ensure the safe and reliable transfer of power in the Midwest and ensure fair access to the transmission system. ISOs and RTOs provide non-discriminatory transmission access, facilitating competition among wholesale suppliers to improve transmission service and provide fair electricity prices. Across large regions, they schedule the use of transmission lines; manage the interconnection of new generation and monitor the markets to ensure fairness and neutrality for all participants.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

Organization of Midwest ISO States ("OMS"): A group of state utility commissions in the MISO footprint that initiated the formation of the country's first so-called regional

state committee. The OMS will act as an adviser on some MISO functions and attempt to plan transmission investments on a regional, rather than state-specific basis.

PJM Interconnection: The PJM Interconnection is the RTO responsible for the operation and control of the bulk power system throughout all or portions of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM became the first fully functioning ISO in 1997. ISOs and RTOs provide non-discriminatory transmission access, facilitating competition among wholesale suppliers to improve transmission service and provide fair electricity prices. Across large regions, they schedule the use of transmission lines; manage the interconnection of new generation and monitor the markets to ensure fairness and neutrality for all participants.

Pulverized Coal: Coal that is ground into dust using a powdered coal mill and used as the fuel in a power plant to generate electricity.

Public Utility Holding Company Act of 1935 ("PUHCA"): A federal law to facilitate regulation of electric utilities, by either limiting their operations to a single state, and thus subjecting them to effective state regulation, or forcing divestitures so that each became a single integrated system service a limited geographic area. Another purpose of PUHCA was to keep utility holding companies engaged in regulated businesses from engaging in unregulated businesses. PUHCA required Securities and Exchange Commission approval prior to a holding company engaging in a non-utility business and that such businesses be kept separate from the regulated business. PUHCA was repealed by the Energy Policy Act of 2005, and replaced by what is known as "PUHCA 2005".

Public Utility Regulatory Policies Act ("PURPA"): A federal law passed in 1978 as part of the National Energy Act. It was meant to promote greater use of renewable energy. Implementation of the act was left to the states. PURPA was amended in 2005 by EPAct sections 1251 through 1254.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

State Estimator: A sophisticated mathematical "what if" simulator that allows operators and engineers to evaluate the health of the power system every few minutes by simulating the grid's response to hypothetical equipment failures.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Voltage: The rate at which energy is drawn from a source that produces a flow of electricity in a circuit; expressed in volts.

V. LIST OF ACRONYMNS

AEP	American Electric Power
ARP	Alternative Regulation Plan
BTU	British Thermal Unit
CA	Control Area
CAC	Citizens Action Coalition
CAIDI	Customer Average Interruption Duration Index
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCT	Clean Coal Technology
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERO	Electric Reliability Organization
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FTR	Financial Transmission Rights
GIS	Geographic Information Systems
IDEM	Indiana Department of Environmental Management
IDP	Intermediate Dispatchable Power
IGCC	Integrated Gasification Combined Cycle
I&M	Indiana Michigan Power Company, subsidiary of AEP
IMPA	Indiana Municipal Power Agency
IOU	Investor-owned Utility
IPL	Indianapolis Power and Light
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
JDMA	Joint Development and Marketing Agreement
LMP	Locational Marginal Pricing
MOU	Memorandum of Understanding
MW	Megawatt
MWH	Megawatt Hour
MISO	Midwest Independent Transmission System Operator
MTEP	Midwest ISO Transmission Expansion Plan

NERC	North American Electric Reliability Council
NO_x	Nitrogen Oxides
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
OMS	Organization of Midwest ISO States
OUCC	Office of Utility Consumer Counselor
PJM	The PJM Interconnection
PPA	Purchase Power Agreement
PPTT	Purchased Power and Transmission Tracker
PSI	PSI Energy
PUHCA	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
REMC	Rural Electric Membership Cooperative
RPM	Reliability Pricing Model
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SIGECO	Southern Indiana Gas & Electric Company
SO_2	Sulfur Dioxide
TLR	Transmission Loading Relief
WVPA	Wabash Valley Power Association